REBUTTAL TESTIMONY

of

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Rate Analyst

Rates Department
Financial Analysis Division
Illinois Commerce Commission

Proposed General Increase in Gas Rates

Mid American Energy Company

Docket No. 01-0696

April 30, 2002

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Witness Identification

Q. Please state your name and business address.

A. Mike Luth, Illinois Commerce Commission ("Commission"), 527 East Capitol Avenue, Springfield, Illinois 62701.

Q. Are you the same Mike Luth who pre-filed direct testimony on behalf of the Commission Staff, identified as ICC Staff Exhibit 5.0?

A. Yes, I am.

Introduction to Testimony

Q. What is the subject matter of your rebuttal testimony?

A. In my rebuttal testimony, I am replying to the rebuttal testimony of MidAmerican Energy Company ("MEC" or the "Company") witnesses Charles B. Rea and Gregory C. Schaefer, which was pre-filed on April 4, 2002. Both Mr. Rea and Mr. Schaefer commented on my direct testimony. In addition, I am increasing the amount of revenues associated with the contract transportation of gas for the Cordova Energy Center ("CEC"), an MEC affiliate.

Q. Are you sponsoring any schedules as part of your testimony?

A. Yes, I am sponsoring the following schedules:

Schedule 1	Rate Design
Schedule 2	Customer Class Allocation Factors
Schedule 3	Peak Demand Estimation
Schedule 4	Calculation of Load Factor
Schedule 5	Functional Allocation Factors

Summary of Rebuttal Testimony

Q. Please summarize your rebuttal testimony.

A. I have considered the rebuttal testimony of Mr. Rea and Mr. Schaefer, reviewed information provided by MEC in reply to additional data requests, and have made the following changes to my direct testimony:

- Accepted the Company's calculation of the ratio of average demand-related costs and peak demand-related costs,
- Adjusted the Company's projection of the class-by-class peak demand so that the temperature-related change in gas use is based upon an 85 Heating Degree Day ("HDD") maximum, rather than the Company's use of a 90 HDD maximum,
- Increased the offset to revenues to be collected from the Transportation Administration Charge ("TAC") as a result of a greater test year amount of Miscellaneous Transportation Revenues, consistent with the amount of Miscellaneous Transportation Revenues that Mr. Schaefer included in his rebuttal testimony,
- Accepted the Company's cost of service study treatment of Federal Energy Regulatory Commission ("FERC") account no. 923, Outside Services, so that it is functionally allocated according to Operating and Maintenance ("O & M") expense, rather than payroll,
- Constrained the increase in the Rate 85 Customer Charge so that it is $1,200.00 per month,
- Reduced the amount of the increase in the Rate 70 Customer Charge so that it is $19.00,
- Reduced the amount of unrecovered Rate 60 costs to be recovered by Rate 85 by reducing the Rate 60 Energy Charge, resulting in a combination of the Rate 60 Customer Charge and Energy Charge that recovers nearly all of the Rate 60 costs, and
- Allocated a percentage of Rate 70 and Rate 85 Energy costs away from Sales customers to Transportation customers, while maintaining a differential in the Energy Charge to Sales customers compared to Transportation customers.

Q. Have you changed your position on the weighting of Services, Meters and Regulators based upon the rebuttal comments of Mr. Rea regarding your use of the weighting factors from the Order in the previous MEC gas rate Docket No. 99-0534?

A. No, I have not. Mr. Rea's comments are not persuasive to make the significant changes in weights from Docket No. 99-0534 that he is proposing.

Cost of Service Study

Peak Demand

Q. Why have you accepted the Company's position on peak demand?

A. In preparing my direct testimony, I misinterpreted the Company's reply to a data request in observing that the Company's all-time throughput was considerably less than the system design peak throughput calculated by Mr. Rea. While I had read the correct number, I misread the unit of measure. The information provided in the Company's reply to my data request represented a system-wide peak measured in dekatherms, which is 10 therms. Prior to Mr. Rea's rebuttal testimony, I became aware of my mistake and reviewed Mr. Rea's projection of the Illinois peak again, and I find that it is reasonable given that the Company has estimated the Illinois all-time peak on February 2, 1996 to be 1,502,580 therms, which is more than 99 percent of the 1,513,380 therm peak projected by Mr. Rea.

Q. What is the effect of your acceptance of Mr. Rea's projection of the Illinois peak demand?

A. By accepting Mr. Rea's projection of the Illinois peak demand, the percentage of Mains-related costs allocated on the basis of average daily throughput is approximately 36.9%, compared to 48.9% in my direct testimony. The remainder of Mains-related costs is allocated on the basis of peak demand. The change in peak demand results in an increase in the percentage of Mains-related costs allocated on the basis of peak demand, and a decrease in the percentage of Mains-related costs allocated on the basis of average daily throughput.

Q. Have you accepted Mr. Rea's projection of the class-by-class peaks?

A. For the most part, I have accepted Mr. Rea's projection, but I have adjusted the maximum HDD used to project the effect of temperature upon gas consumption. Instead of 90 HDD included in Mr. Rea's projection, I have used 85 HDD. 85 represents the all-time record number of HDD at the National Weather Service's Moline, Illinois station, which occurred on February 3, 1996. The high temperature on February 3, 1996 at the Moline station was –11 degrees and the low was –28, for a mean temperature of –19.5 degrees. The February 3, 1996 mean temperature of –19.5 is 84.5 degrees less than 65 degrees, which is the baseline for measuring HDD. It is appropriate to measure peak demand based upon the all-time HDD because the data represents the region's most extreme cold over several decades. Since the all-time HDD is lower than 90, class-by-class peak is somewhat lower in my cost of service study ("COSS") than in Mr.

Rea's COSS. Gas usage by customer classes with lower load factors is more affected by changes in temperature. Low load factor customers thus have a somewhat reduced percentage of Mains-related costs allocated according to peak demand in my COSS because of my use of somewhat less extreme weather conditions as the basis for the projection of peak gas usage, resulting in lower projected peak use.

Miscellaneous Gas Transportation Revenues

Q. What is the amount of increase in Miscellaneous Gas Transportation Revenues compared to your testimony?

A. I am including $36,326 in Miscellaneous Gas Transportation Revenues in my rebuttal COSS, compared to $12,933 in my direct testimony. The difference results from the elimination of Pipeline Transportation revenues over-recovered through the Purchased Gas Adjustment Clause ("PGA") in the determination of Miscellaneous Gas Transportation Revenues. The over-recovery of PGA-related revenues is refunded in the month-by-month determination of the PGA rate and should not be included in the determination of base rates to be established in this docket.

Q. Is the amount of Miscellaneous Transportation Revenues the same as the amount that Mr. Schaefer used in determining his proposed TAC?

A. Yes, it is, as Mr. Schaefer describes on pages 11 and 12 of his rebuttal testimony. Mr. Schaefer's rebuttal testimony appears to state that I did not credit

Miscellaneous Transportation Revenues against costs to be recovered through the TAC (Rebuttal Testimony of Gregory C. Schaefer, page 11, line 250 through page 12, line 264), but that would be an incorrect conclusion. In direct testimony, I also credited Miscellaneous Transportation Revenues against costs to be recovered through the TAC, which has the effect of reducing the TAC, but the amount was only $12,933. The $23,393 increase in Miscellaneous Transportation Revenues in my rebuttal COSS, divided by 927 annual transportation bills for 78 test year transportation customers, represents a $25.00 reduction in the TAC and accounts for most of the difference between the TAC that I proposed in direct testimony and the TAC that I am now proposing in rebuttal testimony.

<u>Cordova Energy Center Revenues</u>

Q. Why have you increased the amount of CEC revenues that MEC included in its determination of revenues to be recovered by base rates?

A. MEC witness Rick R. Tunning based his estimate of CEC revenues upon the contract that MEC has with its affiliate CEC to supply gas. Mr. Tunning's estimate includes one monthly customer charge of $8,280 per month (Workpaper RRT/K, page 1, line 2). The contract between CEC and MEC, however, includes two customer charges because CEC has two primary receipt points for accepting gas deliveries. The second charge is also referenced in the MEC tariff on file with the Commission that provides the amount that CEC is to pay under contract. Although not included in Mr. Tunning's estimate, the second customer charge of

$6,830 per month appears in the support for Mr. Tunning's estimate (Workpaper RRT/K, page 2, Article VI. Rates, subpart A, 12th line).

Q. Why is the $6,830 monthly customer charge not included in Mr. Tunning's estimate?

A. The Company's reply to Staff data request ML-28 stated that the $6,830 monthly charge was not certain to be paid to MEC because CEC has the option to terminate its right to receive gas at the second primary receipt point and thereby not be charged the monthly charge applicable to that right. The Company's reply to Staff data request ML-29, however, shows that CEC was charged both monthly customer charges through January 2002. MEC has not provided any indication that CEC had provided the required 12-month written notice that CEC wished to terminate its right to accept gas delivered through the second primary receipt point. Given that CEC was charged the second monthly customer charge of $6,830 through January 2002, it is reasonable to conclude that both customer charges will continue to be in effect in the foreseeable future. The amount of revenues to be collected by MEC through its contract with CEC should include both monthly customer charges, so I have increased the amount of revenues collected by MEC from CEC by $81,960 ($6,830 multiplied by 12 months).

Weighting Factors for Services, Meters, and Regulators

Q. Did MEC accept your adjustment to the weighting of Services, Meters and Regulators for determining the class allocation of those costs?

A. No, MEC did not accept my class-by-class weighting adjustments for Services, Meters and Regulators. MEC witness Rea stated that the weightings provided by MEC in Docket No. 99-0534 were not supported by calculations specific to the Company, and were developed through the general experience of the Company's COSS witness in that docket (Rebuttal Testimony of Charles B. Rea, page 24, line 532 through page 25, line 553). Mr. Rea believes that his weightings are more accurate because his weightings are based upon current empirical data. In reply to Staff data request ML-4, Mr. Rea provided the data he used to determine the class weightings.

The problem with Mr. Rea's "current empirical data" is that the allocation of costs of equipment installed in prior years is based upon an estimate of current costs to install standard equipment. In reply to Staff data request ML-37, MEC states that it cannot determine how many "standard" installations, as defined in the reply to Staff data request ML-4, are in place. If the Company cannot determine how many "standard" installations are in place, it is difficult to determine what constitutes a standard installation, if a standard installation exists at all. In addition, the Company's determination of standard costs eliminates installations that cost more than expected. Unless MEC adjusted the plant-in-service accounts to remove the unexpected costs, those unexpectedly high-cost installations remain in rate base. It is not appropriate to allocate the unexpectedly high cost of various installations to other rate classes based upon an adjustment of standard costs resulting from the elimination of those unexpectedly high-cost installations.

Additionally, Mr. Rea's approach introduces marginal cost concepts in an embedded COSS because it applies an estimate of today's costs to install new equipment that may or may not have some relationship to the equipment currently in use, but installed in the past. Mr. Rea criticizes Citizens Utilities Board witness Brian Ross for implementing marginal cost concepts in the Company's embedded COSS (Id., page 17, lines 354-365), yet Mr. Rea implements marginal cost concepts in the weighting of Services, Meters and Regulators. While not describing his use of "current empirical data" as a marginal cost concept, it is nonetheless a marginal cost concept that does not have a place in determining the weighting of embedded plant-in-service costs installed in the past and that will be in use in the foreseeable future. Given that the relationship, if any, between the standard costs reflected in the weightings of Services, Meters and Regulators proposed by Mr. Rea is unclear at best, the general experience relied upon by the MEC COSS witness in the recent Docket No. 99-0534 is at least as reliable in developing weighting factors in the present docket. Since the Commission found the weighting factors for Services, Meters and Regulators in Docket No. 99-0534 to be reasonable, and lacking a compelling and clear reason to significantly adjust those factors only two years later, the Commission should use the same weighting factors as it used in Docket No. 99-0534.

Customer Services

Q. Have you maintained your proposal in direct testimony to allocate marketing costs according to throughput?

A. Yes, I have. MEC witness Rea allocates marketing costs according to margin, explaining that the size of a potential market is represented not only by throughput, but also by margin (Id., page 27, lines 584-592). I agree with Mr. Rea's definition of the potential size of the market, but I do not agree with his allocation of marketing costs according to margin rather than throughput, particularly in a regulated market. Mr. Rea's discussion does not document whether the Company's marketing efforts have been directed more toward high-margin customers than high-volume customers. Under Mr. Rea's COSS, Rate 70 customers would pay approximately 12.8 cents per therm excluding cost of gas, while Rate 85 and Rate 87 customers would pay approximately 4.3 and 3.3 cents per therm, respectively. Mr. Rea's approach would therefore have the paradoxical result of increasing the amounts paid by customers who already pay a higher rate per unit of service (therms), because his approach requires those customers to pay more for the costs of promoting expansion of that service, under the theory that the promotional costs will reduce their costs. In a regulated market, it is more appropriate for customers who pay the least per therm to pay at least as much for marketing costs designed to expand use of the utility service as customers who pay more per therm. My allocation of marketing costs results in Rate 85 and Rate 87 paying the same amount per therm for marketing as Rate 70, not more, but not less.

Rate Design

Rate 60

Q. What changes have you made to Rate 60?

A. Like the other rate classes, Rate 60 has changed as a result of the changes in my COSS. The monthly Customer Charge is slightly higher, up to $10.70 from the $10.30 that I proposed in direct testimony. The volumetric Distribution Energy Charge is lower than I proposed in direct testimony. If the Rate 60 Distribution Energy Charge were not lowered, the costs not recovered through the Rate 60 Customer Charge because of rounding to the nearest dime would have been fairly high, and would have necessarily been recovered through other customer classes. Consistent with my proposal in direct testimony, the increase in the Customer Charge is less than the increase indicated by the COSS – a result which will benefit low-volume Rate 60 customers – and the Distribution Energy Charge is higher than the charge suggested by the COSS, but still less than the current charge.

Rate 70

Q. What changes have you made to Rate 70?

A. I have reduced my proposed increase to the monthly Rate 70 Customer Charge from $25.00 to $19.00, both of which are up from the current $12.50, but less than the level suggested by the COSS. Limiting the increase in the Rate 70 Customer Charge reduces its impact on small customers, but also represents movement toward the cost of service level. Further, in his rebuttal testimony, Mr.

Schaefer proposes the continuation of the current $18.00 Transportation Metering Charge ("MC") in addition to the $85.00 TAC. My proposed $85.00 TAC is lower than $114.00 that I proposed in direct testimony. The MC replaces the Company's proposal to collect the cost of metering upgrades upon the installation of the necessary equipment. Staff witness David A. Borden's direct testimony rejected the collection of metering upgrade costs at the time of installation, so it is not unreasonable to continue the current MC, which is based upon recent cost information. In my design of the Rate 70 Customer Charge, revenues collected from the MC act as an offset to costs to be recovered through the Customer Charge.

I have also changed some of the concepts behind the design of the Rate 70 Distribution Energy Charge by allocating some energy-related costs to transportation customers. It is appropriate to have a differential between the Distribution Energy Charge paid by a sales customer compared to a transportation customer because the energy supply for sales customers is arranged by the Company, while transportation customers typically arrange for their own supplies. Currently, however, transportation customers pay the same Distribution Energy Charge as sales customers, in part to recognize that the Company provides some supply management services to transportation customers in the form of system balancing, particularly during peak demand or other critical days. I have allocated 83% of Rate 70 energy costs to sales customers and 17% to transportation customers. These percentages represent the midpoint between the near 67% of Rate 70 throughput to sales customers and 100% of energy costs. This approach places a value on the supply services provided to transportation customers by MEC, but at a reduced charge to recognize that transportation customers arrange for their own gas supply.

Rate 85

Q. What changes have you made to Rate 85?

A. As with Rate 70, I have allocated a portion of Rate 85 energy costs to transportation customers to recognize that transportation customers receive some benefit from energy supply arrangements provided by MEC, but do not receive the same energy-related benefit as sales customers because transportation customers arrange for their own gas supplies. For Rate 85, the percentage allocated to sales customers is 52% of energy costs, which is the midpoint between the 4% of throughput to sales customers and 100% of energy costs.

I have also reduced my proposed Rate 85 monthly customer charge to $1,200, which is less than the level suggested by the COSS, yet the charge represents a significant increase from the current $674 per month. Mr. Schaefer suggests a customer charge of $1,000. Since Rate 85 customers are large customers with significantly higher monthly bills for gas services for significantly higher volumes of gas than Rate 60 and 70 customers, the monthly customer charge is probably less of a concern than the overall average bill. Nonetheless, a $576 increase from $674 to $1,200 is significant, but not as drastic as an increase to $1,969 as suggested by the COSS. Moreover, the Rate 85 customer charge has fluctuated considerably recently. Prior to the Order in Docket No. 99-0534, the Rate 85 customer charge was $1,000. The Order in Docket No. 99-0534, about two years before the Order in this docket will likely be entered, cut the Rate 85 customer charge to $674.00. An increase to $1,200 moves the customer charge to cost of service levels and represents an increase of approximately 20% compared to the customer charge prior to Docket No. 99-0534, and a 78% increase over the current customer charge. An increase to $1,969 would nearly triple the current customer charge. Both the Company and I are proposing some other changes to the makeup of the overall Rate 85 bill, moving the emphasis of recovery of costs from demand-based charges to throughput. Stabilizing the increase in the customer charge, with considerable movement toward cost of service levels, is a reasonable approach.

As with Rate 70, continuation of the current Rate 85 MC is reasonable and serves as an offset to costs recovered by the customer charge. The Rate 85 MC is currently $11.00 per month for Rate 85.

Rate 87

Q. What are your changes to Rate 87?

A. The most significant difference in Rate 87 is that the Distribution Energy Charge is less than I proposed in direct testimony. This reduction is primarily a result of the increase in Mains-related costs allocated according to Peak demand, with a corresponding decrease in Mains-related costs allocated according to throughput. Since Rate 87 is an off-peak rate, costs allocated according to throughput have some relationship to nearly all of the costs to be recovered through the Distribution Energy Charge. With a decrease in Mains-related costs allocated to Rate 87, the Distribution Energy Charge is reduced.

Q. Please address the concerns of MEC witness Schaefer about your proposed near doubling of the monthly Rate 87 customer charge.

A. A near doubling of the monthly Rate 87 customer charge can initially be viewed as significant and of concern. The recent history of Rate 87, however, indicates that, like Rate 85, the Rate 87 customer charge has fluctuated considerably. The Rate 87 customer charge was $400 prior to the Order in Docket No. 99-0534. Since a $400 Rate 87 customer charge was in effect only two years ago, I do not view an increase in the current $160 customer charge to $315 as an onerous increase.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

MidAmerican Energy Company
Rate Design - Summary of Proposed Rates

	Customer Charge per month	Transportation Administrative Charge per month	Transportation Metering Charge per month	Distribution Energy Charge per therm -- Sales	Distribution Energy Charge per therm -- Transportation	Distribution Demand Charge per therm MDR -- Sales	Distribution Demand Charge per therm MDR -- Transportation
Rate 60	$ 10.70			$ 0.07957	-----	-----	-----
Rate 70	$ 19.00	$ 85.00	$ 18.00				
0 - 1,000				$ 0.12437	$ 0.12243	-----	-----
1,001 - 10,000				$ 0.10821	$ 0.10306	-----	-----
10,000 +				$ 0.05964	$ 0.05449	-----	-----
Rate 85	$ 1,200.00	$ 85.00	$ 11.00	$ 0.02629	$ 0.02323	$ 0.25803	0.25803
Rate 87	$ 315.00	$ 85.00	$ 18.00	$ 0.03718	$ 0.03076	-----	-----

Distribution Energy Charge for Rate 87 Transportation is the Sales Distribution Energy Charge discounted by Energy Costs per therm. See page 4.

Mid-American Energy Company
Rate Design

	Net COS	Rate 60	Rate 70	Rate 85	Rate 87
Transportation Metering Charge			**$ 18.00**	**$ 11.00**	**$ 18.00**
Transportation Bills			834	86	7
Revenue Recovery	$ 16,084		$ 15,012	$ 946	$ 126
Customer Costs:	$ 11,713,338	$ 8,609,919	$ 2,914,229	$ 182,361	$ 6,828
Multiplied by: Staff Revenue Adjustment Factor (see page 6)	0.98571	0.98571	0.98571	0.98571	0.98571
	$ 11,546,003	$ 8,486,920	$ 2,872,597	$ 179,755	$ 6,731
Less: Transportation Metering Charge Revenues	$ (16,084)		$ (15,012)	$ (946)	$ (126)
Net Customer Costs	$ 11,529,919		$ 2,857,585	$ 178,809	$ 6,605
Less: Over-recovered Demand and Energy Costs (Rate 60 only)	$ (760,646)	$ (760,646)			
Plus: Under-recovered Rate 60 Customer Costs				$ 414	
Costs to be Recovered through Customer Charge	$ 10,769,273	$ 7,726,274	$ 2,857,585	$ 179,223	$ 6,605
Divided by: Total Monthly bills		722,043	61,663	91	21
Monthly Customer Charge		**$ 10.70**	**$ 19.00**	**$ 1,200.00**	**$ 315.00**
Multiplied by: Total Monthly bills		722,043	61,663	91	21
Revenue Recovery	$ 9,013,272	$ 7,725,860	$ 1,171,597	$ 109,200	$ 6,615
Over/(under) recovery	$ (1,756,001)	$ (414)	$ (1,685,988)	$ (70,023)	$ 10
Transportation Administration Costs:	$ 82,675	$ -	$ 74,195	$ 7,420	$ 1,060
Multiplied by: Staff Revenue Adjustment Factor (see page 6)	0.98571	-	0.98571	0.98571	0.98571
	$ 81,493	$ -	$ 73,135	$ 7,314	$ 1,045
Divided by: Total Monthly bills			834	86	7
Monthly Transportation Administration Charge			**$ 85.00**	**$ 85.00**	**$ 85.00**
Multiplied by: Total Monthly bills			834	86	7
Revenue Recovery	$ 78,795		$ 70,890	$ 7,310	$ 595
Over/(under) recovery	$ (2,698)	$ -	$ (2,245)	$ (4)	$ (450)

Mid-American Energy Company
Rate Design

	Net COS	Rate 60	Rate 70	Rate 85	Rate 87
Demand Costs:	$ 6,060,677	$ 3,417,060	$ 2,034,801	$ 600,657	$ 8,158
Multiplied by: Staff Revenue Adjustment Factor (see page 6)	0.98571	0.98571	0.98571	0.98571	0.98571
	$ 5,974,095	$ 3,368,245	$ 2,005,732	$ 592,076	$ 8,041
Distribution Demand Charge per MDR therm (Rate 85 only)				**see page 6**	
Revenue Recovery	$ 280,221			$ 280,221	
Over/(under) recovery	$ (5,693,874)	$ (3,368,245)	$ (2,005,732)	$ (311,855)	$ (8,041)
Energy Costs:	$ 993,188	$ 706,142	$ 280,767	$ 4,483	$ 1,796
Multiplied by: Staff Revenue Adjustment Factor (see page 6)	0.98571	0.98571	0.98571	0.98571	0.98571
	$ 979,000	$ 696,054	$ 276,756	$ 4,419	$ 1,770
Plus or (minus) under-recovered/(over)-recovered Customer Costs	1,756,001		1,685,988	70,023	(10)
Plus or (minus) under-recovered/(over)-recovered Transportation Administration Costs	2,698	-	2,245	4	450
Plus or (minus) under-recovered/(over)-recovered Demand Costs	5,693,874	3,368,245	2,005,732	311,855	8,041
	$ 8,431,573	$ 4,064,299	$ 3,970,722	$ 386,301	$ 10,251
Divided by: Total Billing units (therms)		60,637,738			275,696
Distribution Energy Charge per therm		**$ 0.07957**	**see page 3**	**see page 4**	**0.03718**
Multiplied by: Total Billing units		60,637,738			275,696
Revenue Recovery	$ 9,192,125	$ 4,824,945	$ 3,970,723	$ 386,206	$ 10,251
Over/(under)-recovery	$ 760,551	$ 760,646	$ 1	$ (95)	$ (0)
Total Revenue Recovery	$ 18,580,497	$ 12,550,805	$ 5,228,222	$ 783,883	$ 17,587
Total Unadjusted Costs (see page 6)	18,849,877	12,733,122	5,303,993	794,920	17,842
Multiplied by: Staff Revenue Conversion Factor (see page 7)	0.98571	0.98571	0.98571	0.98571	0.98571
Net Revenues from Base Rates	18,580,591	12,551,219	5,228,221	783,564	17,587
Over/(under)-recovery	$ (94)	$ (414)	$ 1	$ 319	$ (0)

MidAmerican Energy Company
Rate 70 Distribution Energy Charges

	Total	Sales	Transportation	
Energy Costs x Staff Revenue Conversion Factor	$ 276,756	$ 229,708	$ 47,049	83% sales, 17% transportation
Demand Costs:				
Average x Staff Revenue Conversion Factor	743,387	500,224	243,163	Throughput
Peaking x Staff Rev. Conversion Factor	1,262,345	839,823	422,523	Peak
Plus or (minus) under/(over)- recovered customer and transportation administration costs	1,685,988	1,663,331	22,657	Customers
Plus or (minus) under/(over)- recovered transportation administration costs	2,245		2,245	
	$ 3,970,722	$ 3,233,086	$ 737,636	
Divided by: Throughput	39,404,125	26,290,065	13,114,060	GCS-1, Schedule 2, page 1
Average per therm	0.10077	0.12298	0.05625	
Average Energy Costs per therm	0.00702	0.00874	0.00359	
Average Demand Costs per therm	0.05090	$ 0.05097	$ 0.05076	
Average Unrecovered Customer Costs per therm	$ 0.05714	$ 0.06947	$ 0.00413	First 2 blocks, GCS-3, page 1
Average Unrecovered Transportation Administration Costs per therm			$ 0.00321	First 2 blocks, GCS-3, page 1

MidAmerican Energy Company
Rate 70 Distribution Energy Charges

Block Charges per therm:	Sales	Transportation		
0-1,000				
Unrecovered Customer Costs per therm + Block Increase	$ 0.06473	$ 0.06473		
Plus: Unrecovered Transportation Administration Costs per therm		0.00321		
Plus: Demand Costs per therm	0.05090	0.05090		
Plus: Energy Costs per therm	0.00874	0.00359		
	0.12437	**0.12243**		
Multiplied by: Billing units (therms)	14,859,979	774,706	WP GCS-3a	
Revenue Recovery	$ 1,848,136	$ 94,847		
1,001-10,000				
Customer Costs per therm x .85	$ 0.04857	$ 0.04857		
Plus: Demand Costs per therm	0.05090	0.05090		
Plus: Energy Costs per therm	0.00874	0.00359		
Distribution Energy Rate per therm	**0.10821**	**0.10306**		
Multiplied by: Billing units (therms)	9,163,856	4,706,391	WP GCS-3a	
Revenue Recovery	$ 991,621	$ 485,041		
10,001+				
Demand Costs per therm	0.05090	0.05090		
Energy Costs per therm	0.00874	0.00359		
Distribution Energy Rate per therm	**0.05964**	**0.05449**		
Multiplied by: Billing units (therms)	2,266,230	7,632,962	WP GCS-3a	
Revenue Recovery	$ 135,158	$ 415,920		
Total Revenue Recovery	$ 2,974,915	$ 995,808		$ 3,970,723

MidAmerican Energy Company
Rate 85 Distribution Demand and Energy Charges

	Total	Sales	Transportation	
Energy Costs x Staff Revenue Conversion Factor	$ 4,419	$ 2,298	$ 2,121	
Divided by: Billing units (therms)	16,530,375	720,595	15,809,780	
Energy Costs per billing unit	$ 0.00027	$ 0.00319	$ 0.00013	
Demand Costs:				
Average x Staff Revenue Conversion Factor	311,857	13,595	298,263	Throughput
Peaking x Staff Rev. Conversion Factor	280,219	14,958	265,261	Peak
Plus or (minus) under/(over)- recovered transportation administration costs	4		4	
	$ 596,499	$ 30,850	$ 565,649	
Demand Charge per Maximum Daily Requirement ("MDR"):				
Peaking Demand Costs	$ 280,219			
Less: Over-recovered Transportation Adm. Costs			4	
Divided by: Demand billing units (MDR therms)	1,086,000		1,059,000	
Cost/(credit) per MDR therm	$ 0.25803		-	
Distribution Demand Charge per MDR therm		**$ 0.25803**	**$ 0.25803**	
Multiplied by: Demand Billing Units		27,000	1,059,000	WP GCS-3b
Revenue Recovery		$ 6,967	$ 273,254	$ 280,221
Energy Charge per therm:				
Average Demand Costs	$ 311,857			
Plus: Unrecovered Customer Costs	70,023			
	$ 381,881			
Divided by: Energy Billing units (therms)	16,530,375			
	$ 0.02310			
Plus: Energy Costs per therm		$ 0.00319	$ 0.00013	
Distribution Energy Charge per therm		**$ 0.02629**	**$ 0.02323**	
Multiplied by: Energy Billing Units		720,595	15,809,780	
Revenue Recovery		$ 18,944	$ 367,261	$ 386,206
				$ 666,427

Mid-American Energy Company
Rate Design - Summary of Costs by Function and
Staff Revenue Conversion Factor

Functional Costs	Net COS	Rate 60	Rate 70	Rate 85	Rate 87	Allocation Method
Demand-related Costs						
Mains (Average)	2,238,268	1,160,554	754,161	316,377	7,177	Throughput (Weather Normalized)
Mains (Peaking)	3,822,408	2,256,507	1,280,640	284,280	981	Peak Demand (Total Throughput)
	$ 6,060,677	$ 3,417,060	$ 2,034,801	$ 600,657	$ 8,158	
Customer-related Costs						
Services	$ 3,712,581	$ 2,597,512	$ 1,109,242	$ 5,180	$ 648	Weighted Customers - Services
Meters	3,734,400	2,584,677	1,103,760	42,956	3,007	Weighted Customers - Meters
Regulators	464,544	321,523	137,303	5,344	374	Weighted Customers - Regulators
Industrial Meters	15,112	-	4,822	10,290	-	Weighted Customers - Industrial Meters
Customer Accounts	3,786,700	3,106,208	559,102	118,590	2,800	Weighted Customers - Cust Service
	$ 11,713,338	$ 8,609,919	$ 2,914,229	$ 182,361	$ 6,828	
Transportation Administration	$ 82,675	-	$ 74,195	$ 7,420	1,060	Transport Customers
Energy Costs						
Cost of Gas	$ 48,868,872	$ 33,596,583	$ 14,758,282	$ 273,151	$ 240,856	Cost of Gas (Direct Assigned)
Less: PGA Recoveries	(48,535,381)	(33,367,313)	(14,657,568)	(271,287)	(239,213)	
	$ 333,491	$ 229,270	$ 100,713	$ 1,864	$ 1,644	
Peak Facilities	659,697	476,872	180,054	2,619	152	Peak Demand (Sales Service Only)
	$ 993,188	$ 706,142	$ 280,767	$ 4,483	$ 1,796	
Total Costs (unadjusted to Staff)	$ 18,849,877	$ 12,733,122	$ 5,303,993	$ 794,920	$ 17,842	

Staff Revenue Requirement	$ 19,200,000	
Less: Other Operating Revenues	(619,409)	
Net Revenue from Base Rates	$ 18,580,591	same as page 3, Total Costs adjusted by Staff Revenue Conversion Factor
Divided by: ML Cost Study Revenue Requirement (unadjusted)	18,849,877	
Staff Revenue Conversion Factor	**0.98571**	used in calculating charges on pages 2 and 3

MidAmerican Energy Company
Customer Class Allocators

I. Throughput (Weather Normalized)

	60	70	85	87	Total (w/o Contract)
W.N. Throughput	60,637,738	39,404,125	16,530,375	374,989	116,947,227
Allocator	**0.5185051**	**0.3369394**	**0.1413490**	**0.0032065**	**1.0000000**

II. Peak Demand (Sales Service Only)

	60	70	85	87	Total (w/o Contract)
Allocator	**0.7228653**	**0.2729338**	**0.0039699**	**0.0002310**	**1.0000000**

III. Peak Demand (Total Throughput)

	60	70	85	87	Total (w/o Contract)
Allocator	**0.5903364**	**0.3350350**	**0.0743720**	**0.0002566**	**1.0000000**

IV. Customers

	60	70	85	87	Total (w/o Contract)
Total Customers	60,170	5,139	8	2	65,319
Allocator	**0.9211715**	**0.0786754**	**0.0001225**	**0.0000306**	**1.0000000**

V. Transport Customers

	60	70	85	87	Total (w/o Contract)
Total Customers	-	70	7	1	78
Allocator	**-**	**0.8974359**	**0.0897436**	**0.0128205**	**1.0000000**

VI. Weighted Customers - Services

	60	70	85	87	Total (w/o Contract)
Total Customers	60,170	5,139	8	2	65,319
Weight	1.00	5.00	15.00	7.50	N/A
Weighted Customers	60,170	25,695	120	15	86,000
Allocator	**0.6996512**	**0.2987791**	**0.0013953**	**0.0001744**	**1.0000000**

MidAmerican Energy Company
Customer Class Allocators

VII. Weighted Customers - Meters

	60	70	85	87	Total (w/o Contract)
Total Customers	60,170	5,139	8	2	65,319
Weight	1.00	5.00	125.00	35.00	N/A
Weighted Customers	60,170	25,695	1,000	70	86,935
Allocator	**0.6921263**	**0.2955657**	**0.0115028**	**0.0008052**	**1.0000000**

VIII. Weighted Customers - Regulators

	60	70	85	87	Total (w/o Contract)
Total Customers	60,170	5,139	8	2	65,319
Weight	1.00	5.00	125.00	35.00	N/A
Weighted Customers	60,170	25,695	1,000	70	86,935
Allocator	**0.6921263**	**0.2955657**	**0.0115028**	**0.0008052**	**1.0000000**

IX. Weighted Customers - Industrial Meters

	60	70	85	87	Total (w/o Contract)
Eligible Customers	-	82	7	-	89
Weight	1.00	5.00	125.00	35.00	N/A
Weighted Customers	-	410	875	-	1,285
Allocator	**-**	**0.3190661**	**0.6809339**	**-**	**1.0000000**

X. Weighted Customers - Customer Service - see page 4

	60	70	85	87	Total (w/o Contract)
Total Customers	60,170	5,139	8	2	65,319
Weight	1.00	2.11	287.15	27.12	N/A
Weighted Customers	60,170	10,830	2,297	54	73,352
Allocator	**0.8202941**	**0.1476490**	**0.0313175**	**0.0007394**	**1.0000000**

MidAmerican Energy Company
Customer Class Allocators

XI. Manufactured Gas Cleanup

	60	70	85	87	Total (w/o Contract)
Throughput	60,637,738	39,404,125	16,530,375	374,989	
Revenue	44,518,635	19,066,105	995,271	258,240	
COG	33,367,314	14,657,569	271,287	239,213	
Total Margin	$ 11,151,321	$ 4,408,536	$ 723,984	$ 19,027	$ 16,302,869
Margin Allocator	0.6840097	0.2704148	0.0444084	0.0011671	1.0000000
Throughput Allocator	0.5185051	0.3369394	0.1413490	0.0032065	1.0000000
50/50	**0.6012574**	**0.3036771**	**0.0928787**	**0.0021868**	**1.0000000**

XII. Cost of Gas

	60	70	85	87	Total (w/o Contract)
Cost of Gas	$ 33,367,314	$ 14,657,569	$ 271,287	$ 239,213	$ 48,535,382
Allocator	**0.6874843**	**0.3019976**	**0.0055895**	**0.0049286**	**1.0000000**

MidAmerican Energy Company
Class Allocation Factors

Calculation of Customer Service Weighting Factor

Category of Expense	Amount	Rate 60	Rate 70	Rate 85	Rate 87		
Direct Customer Accounting Expenses	$ 1,604,530	60,170	5,139	8	2		
Acounts 903-905		1.00	1.00	1.00	1.00		
		60,170	5,139	8	2	65,317	Original Weighted Customers
		0.92120	0.07868	0.00012	0.00003	1.00000	
		$ 1,478,093	$ 126,241	$ 197	$ 49	$ 1,604,530	
Direct Customer Information Expenses	$ 49,541	60,170	5,139	8	2		
Accounts 908-910		1.00	1.00	1.00	1.00		
		60,170	5,139	8	2	65,317	Number of Customers
		0.92120	0.07868	0.00012	0.00003	1.00000	
		$ 45,637	$ 3,898	$ 6	$ 2	$ 49,541	
Economic Development Expenses	$ 57,196	$ 11,151,321	$ 4,408,536	$ 723,984	$ 19,027		
Activity 689302		1.00	1.00	1.00	1.00		
		11,151,321	4,408,536	723,984	19,027	$ 16,283,842	Margins
		0.68481	0.27073	0.04446	0.00117	1.00000	
		$ 39,168	$ 15,485	$ 2,543	$ 67	$ 57,196	
Marketing/EC Expenses	$ 192,614	-	39,404,125	16,530,375	374,989	55,934,500	throughput
Accounts 912-916 Less Activity 689302		-	0.70447	0.29553	0.00670	1.00000	
		$ -	$ 135,691	$ 56,923	$ 1,291	$ 192,614	
Totals		$ 1,562,898	$ 281,314	$ 59,669	$ 1,409		
		60,170	5,139	8	2		
		$ 25.97	$ 54.74	$ 7,458.62	$ 704.39		
Customer Account Weights		**1.000**	**2.107**	**287.149**	**27.118**		
Rounded Weights		**1.000**	**2.000**	**200.000**	**15.000**		

MidAmerican Energy Company
Peak Demand Estimation

(therms)

Month	Rate 60	Rate 70	Rate 85	Rate 87	HDD	70 Sales
Jan	11,064,039	6,797,249	2,070,360	17,643	1,268	5,192,340
Feb	8,046,801	5,835,260	2,193,481	-	863	3,899,068
Mar	5,658,784	3,930,449	1,891,382	11,526	606	2,443,622
Apr	3,902,283	2,797,673	1,584,144	5,970	427	1,645,074
May	2,149,331	1,860,978	1,479,846	4,513	112	804,427
Jun	1,279,506	1,025,347	1,205,653	85,056	29	459,395
Jul	1,277,596	1,235,596	1,146,228	59,636	-	598,508
Aug	1,310,290	874,376	810,512	25,441	-	399,132
Sep	1,464,309	1,509,052	808,773	41,720	97	637,184
Oct	2,733,971	1,906,646	730,429	29,087	263	1,073,422
Nov	7,639,933	3,897,112	931,094	54,855	866	3,092,289
Dec	12,803,430	6,992,428	1,678,470	39,542	1,601	5,303,646
Intercept	1,079,327	1,139,964	1,078,289	36,761		407,296
Slope	7,563	4,074	586	(11)		3,369
Estimated Annual Sales	61,478,259	39,819,222	16,696,686	371,926		26,504,989
Average Load	167,973	108,796	45,619	1,016		72,418
Estimated Peak Day	678,271	383,677	85,130	288	1,147,367	316,591
Estimated Load Factor	24.76%	28.36%	53.59%	352.31%		22.87%
W.N. Total Throughput	60,637,738	39,404,125	16,530,375	374,989		
W.N. Peak Demand	668,998	379,678	84,282	291	1,133,248	
Allocator	0.59034	0.33503	0.07437	0.00026	1.00000	
W.N. Total Sales	60,637,738	26,215,078	720,595	275,696		
W.N. Peak Demand	668,998	252,595	3,674	214	925,480	
Allocator	0.72287	0.27293	0.00397	0.00023	1.00000	

MidAmerican Energy Company
Calculation of Load Factor

(therms)	Total	Sales	Transport	Interdept Sales	Interdept Transport	Total Sales	Total Transport
60	60,637,738	60,637,738	-	-	-	60,637,738	-
70	39,404,125	26,215,078	12,719,450	74,987	394,610	26,290,065	13,114,060
85	16,530,375	720,595	15,809,780	-	-	720,595	15,809,780
87	374,989	275,696	99,293	-	-	275,696	99,293
Contract	87,610,364	-	87,610,364	-	-	-	87,610,364
Total Throughput	204,557,591	87,849,107	116,238,887	74,987	394,610	87,924,094	116,633,497
Average Throughput	558,901						
System Peak	1,513,380						
Load Factor	36.931%						

MidAmerican Energy Company
Functional Allocation Factors

		Peak Facilities	Mains (Average)	Mains (Peak)	Services	Meters	Regulators
1	Peaking Facilities	1.0000000	-	-	-	-	-
2	Average & Peak	-	0.3693100	0.6306900	-	-	-
3	Services	-	-	-	1.0000000	-	-
4	Meters	-	-	-	-	1.0000000	-
5	Regulators	-	-	-	-	-	1.0000000
6	Direct Assign - Non Residential Customers	-	-	-	-	-	-
7	Customer Accounts	-	-	-	-	-	-
8	COG	-	-	-	-	-	-
9	MGP Cleanup	-	-	-	-	-	-
10	Transportation Administration	-	-	-	-	-	-
19	Supervised O&M	0.0337594	0.0847645	0.1447568	0.1611660	0.2573787	0.0300073
20	Gross Production, Distribution Plant	0.0429108	0.2009406	0.3431568	0.2899491	0.1014322	0.0195942
21	Gross Plant	0.0417841	0.1866367	0.3187292	0.2740929	0.1206328	0.0208763
22	Net Plant	0.0340223	0.1836433	0.3136173	0.2712946	0.1275220	0.0214354
23	Gross Distribution Plant	-	0.2099498	0.3585422	0.3029489	0.1059799	0.0204727
24	Meters & Services Plant	-	-	-	0.7408353	0.2591647	-
27	Gross Mains and Services Plant	-	0.2326153	0.3972492	0.3701355	-	-
28	Gross Meters and Regulators Plant	-	-	-	-	0.8381000	0.1619000
29	Gross Plant Excluding Intangible	0.0419087	0.1882191	0.3214317	0.2758471	0.1185086	0.0207344
30	Distribution Operation Expense Less Supervision	-	0.1293275	0.2208594	0.3721515	0.2421299	0.0350029
31	Distribution Maintenance Expense Less Supervision	-	0.1588135	0.2712141	0.1342896	0.3651458	0.0705370
32	Cust Acct Expense Less Supervision	-	-	-	-	0.2276883	-
33	Payroll Allocator	0.0307501	0.0733953	0.1253410	0.1715111	0.2666402	0.0268966
34	Customer and A&G (excludes 923, 925, 926 and 931)	0.015004	0.039587	0.067605	0.073751	0.244206	0.013165
35	Weighted Injuries and Damages	0.044841	0.105636	0.180401	0.257474	0.262038	0.039107

MidAmerican Energy Company
Functional Allocation Factors

		Industrial Meters	Customer Service	Transport Admin	COG	Total
1	Peaking Facilities	-	-	-	-	1.0000000
2	Average & Peak	-	-	-	-	1.0000000
3	Services	-	-	-	-	1.0000000
4	Meters	-	-	-	-	1.0000000
5	Regulators	-	-	-	-	1.0000000
6	Direct Assign - Non Residential Customers	1.0000000	-	-	-	1.0000000
7	Customer Accounts	-	1.0000000	-	-	1.0000000
8	COG	-	-	-	1.0000000	1.0000000
9	MGP Cleanup	-	-	-	-	-
10	Transportation Administration	-	-	1.0000000	-	1.0000000
19	Supervised O&M	0.0001800	0.2511047	0.0088375	0.0280450	1.0000000
20	Gross Production, Distribution Plant	0.0020163	-	-	-	1.0000000
21	Gross Plant	0.0017902	0.0309167	0.0010881	0.0034530	1.0000000
22	Net Plant	0.0017339	0.0407463	0.0014341	0.0045508	1.0000000
23	Gross Distribution Plant	0.0021067	-	-	-	1.0000000
24	Meters & Services Plant	-	-	-	-	1.0000000
27	Gross Mains and Services Plant	-	-	-	-	1.0000000
28	Gross Meters and Regulators Plant	-	-	-	-	1.0000000
29	Gross Plant Excluding Intangible	0.0018152	0.0274964	0.0009677	0.0030710	1.0000000
30	Distribution Operation Expense Less Supervision	0.0005287	-	-	-	1.0000000
31	Distribution Maintenance Expense Less Supervision	-	-	-	-	1.0000000
32	Cust Acct Expense Less Supervision	-	0.7723117	-	-	1.0000000
33	Payroll Allocator	0.0001979	0.2566738	0.0118660	0.0367281	1.0000000
34	Customer and A&G (excludes 923, 925, 926 and 931)	0.000110	0.516394	0.018174	0.012002	1.0000000
35	Weighted Injuries and Damages	0.000296	0.050804	0.002349	0.057055	1.0000000